STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 98-496

July 24, 1998

PUBLIC UTILITIES COMMISSION
Load Obligation and Settlement
Calculations for Competitive Providers
of Electricity (Chapter 321)

NOTICE OF RULEMAKING

WELCH, Chairman; NUGENT, Commissioner

I. INTRODUCTION

The purpose of this Rule is to establish the process, methods and terms by which transmission and distribution utilities will develop the hourly load estimates and monthly energy reconciliations of competitive electricity providers' load obligations, including load profiling and individual customer metering requirements. The estimates will be provided to the bulk power system administrators operating in the State, which will balance each competitive electricity provider's hourly load obligations with its delivered generation to determine the appropriate financial settlement between the bulk power system administrators and the competitive electricity provider.

II. BACKGROUND

During its 1997 session, the Legislature fundamentally altered the electric utility industry in Maine by deregulating electric generation services and allowing for retail competition beginning on March 1, 2000.[1] At that time, Maine's electricity consumers will be able to choose a generation provider from a competitive market. As part of the restructuring process, the Act requires utilities to divest their generation assets and prohibits their participation in the generation services market.

Concurrently, NEPOOL and the recently created ISO-NE are revising existing structures and procedures to accommodate deregulation. The Independent System Operator (ISO-NE) will schedule regional generation dispatch and administer a regional bidding pool for energy and other energy-related products. The precise processes required for effective interaction among ISO-NE, transmission and distribution utilities, and competitive electricity providers are still under development at ISO-NE.

Northern portions of Maine do not operate within the ISO-NE bulk power system territory. Rather, these portions of the State

[1] An Act to Restructure the State's Electric Industry (the Act), P.L. 1997, ch.316 codified as 35-A M.R.S.A. § 3201-3217.

operate in the Maritime control area, whose processes are unrelated to events occurring in the rest of New England. Processes for implementing open access in the Maritime control area are under review by the Commission at this time.

While ISO-NE and Northern Maine procedures are not yet fully developed, it is clear that effective operation of open access requires that the regional bulk power system administrators be capable of balancing the retail load obligations of each competitive electricity provider with the generation delivered by the provider. It is likely that each competitive electricity provider will notify ISO-NE daily[2] of its expected load obligation for the following day to allow ISO-NE to dispatch adequate regional generation. It is also likely that after each day, transmission and distribution utilities will provide ISO-NE with estimates of the loads served by each competitive provider, to allow daily tracking of system reliability and balance and initial financial settlement. Finally, for the purpose of final financial settlement, at the end of each month the ISO-NE likely will balance each competitive electricity provider’s load obligations and generation delivery.

Currently installed metering and communication technology is not adequate to report hourly load obligations for each customer of each competitive electricity provider. Therefore, methods and processes must be developed to provide or estimate the hourly and monthly load calculations that will be required by ISO-NE on March 1, 2000, for financial settlement purposes.

III. THE INQUIRY PROCEEDING

Prior to developing this proposed Rule, we conducted an Inquiry in Docket No. 97-861. We solicited written comments by issuing Notices of Inquiry on December 2, 1997 and on March 3, 1998. Two technical conferences were held, on February 11, 1988 and June 16, 1998. To solicit complete information on the issues, we invited comment from parties who have expressed interest in restructuring in Maine, from competitive electricity providers operating in the region, and from NEPOOL. We received written comments from Bangor Hydro-Electric Company, Central Maine Power Company,[3] Dirigo Electric Cooperative, Eastern Maine Electric Cooperative, ENRON, Maine Public Service Company, and the State Planning Office. Only two commenters were competitive electricity providers. We also received written or verbal

[2]We will often refer to ISO-NE operations and omit reference to Northern Maine, with the understanding that the comments refer to a yet-to-be-developed process in Northern Maine.

[3]Commenters at the technical conferences separately represented the views of the future transmission and distribution utility and the views of the future marketing arm of CMP.

comments from metering equipment manufacturers and consultants with experience in the Massachusetts and the United Kingdom deregulation process. Finally, we obtained a white paper entitled "Direct Access Metering & Data Communication Requirements," commissioned by the National Association of Regulatory Utility Commissioners (NARUC) and prepared by Plexus Research, Incorporated. We used all these sources to inform our opinion of the overall goals, processes, and methodologies to include in the proposed Rule.

IV. DISCUSSION OF INDIVIDUAL SECTIONS

A. General Principles

Three overarching principles guide our development of this Rule. First, we will encourage consistency in methods and processes throughout the State. We initially favored allowing each transmission and distribution utility to develop methods that best suited its existing computer processes and level of expertise. However, comments during the Inquiry stage convinced us that short-term benefits gained by such flexibility would be outweighed by long-term confusion and disagreements caused by a proliferation of methods. Consistency will lower barriers to market entry by minimizing complexity and confusion. Each day, competitive electricity providers will have to predict their hourly load obligations within each transmission and distribution utility's territory so they can schedule resource delivery; inaccuracy could translate to financial loss to the competitive electricity provider. A limited number of well-understood methods for estimating loads will increase accuracy and predictability, affording greater financial stability. Consistency will lower costs by minimizing duplicative research and development. Transmission and distribution utilities may collaborate to develop technological ways of carrying out the provisions of the Rule. Consistency will also minimize potential complaints by competitive electricity providers that believe themselves to be disadvantaged by a transmission and distribution utility settlement calculation. Finally, consistency will improve the understanding and trust of all entities affected by the outcome of the Rule.

Second, we will attempt to minimize costs over the long run by requiring more costly metering only when it is necessary to accurate settlement estimations. We will also minimize costs by remaining mindful that high-volume data storage and processing may cause large incremental costs if computer hardware or software must be replaced or revised. We will attempt to reduce costs by looking ahead to likely future profiling and settlement requirements, and put in place methods that will accommodate those requirements. Finally, we will minimize costs by maintaining consistency across the State, as discussed in the previous paragraph.

Third, the Rule is fairly specific about the methods for developing profiles and making daily or monthly settlement estimations. We originally favored an approach that left methods entirely to the discretion of transmission and distribution utilities. Comments during the Inquiry convinced us that all parties are better served by clarifying the methods and allowing a fixed number of methodological options for carrying out provisions of the Rule. Detailed specifications afford transmission and distribution utilities certainty that their approach will not be subject to costly revisions. It also increases consistency, improving the ability of competitive electricity providers to predict their load obligations. Finally, it reduces future complaints by affected entities.

B. Section 1: Definitions

Section 1 defines terms used in this Rule and are self-explanatory. We included a definition of “winter” and “summer” because transmission and distribution utilities within Maine differ in their definitions of these terms. We are mindful of prevailing ambiguity in the definitions that define load profiles. We invite comment on whether terms are used clearly and usefully throughout this proposed Rule.

C. Section 2: Transmission and Distribution Utility Obligation

Section 2 allows each investor-owned utility to create separate load profiled, but requires consumer-owned utilities to use the profiles of their adjacent investor-owned utility unless good cause exists to produce their own profiles. We investigated the possibility of creating statewide profiles during the Inquiry. Although we do not prohibit statewide profiles, comments convinced us that weather conditions alone would create unacceptable inaccuracies. However, it does not appear necessary or efficient for consumer-owned utilities to create unique load profiles, and indeed many consumer-owned utilities do not currently possess the equipment or expertise to do so. This provision will cause no additional cost to the investor-owned utility, so no fee assessment need be made. It is possible that some profiles will be unacceptably inaccurate for this purpose; in such cases, any party may petition the Commission to allow the consumer-owned utility to develop a unique profile.

Section 2 leaves responsibility for daily and monthly settlement to each utility. We believe that it will be less costly for investor-owned utilities to also use their computer software and technical expertise to perform settlement functions for the consumer-owned utilities, with incremental costs paid by the consumer-owned utilities. However, the necessary data transfer between utilities may cause burdens that offset the benefits gained by eliminating duplicate hardware and software. We invite comment on whether it is preferable to require investor-owned utilities to perform settlement functions for consumer-owned utilities, or whether it is preferable to remain silent on the issue. Such silence would allow this to happen upon agreement between the affected entities.

D. Section 3: Telemetering

Section 3 addresses two issues: *required* telemetering and *optional* telemetering. Commenters strongly supported telemetering for as many customers as possible, citing accuracy as a significant concern in the settlement process. However, all commenters recognized that the cost of telemetering was prohibitive for some customers. We recommend a phase-in approach to telemetering that will allow an orderly transition to 24-hour, real-time telemeters for those customers for whom telemetering is cost-beneficial.

Accordingly, Section 3.A requires telemeters for all customers whose maximum demand exceeds 400 kW. Commenters indicated that the majority of these customers are already telemetered. Costs quoted during the Inquiry to expand telemetering to all large customers did not appear excessive. Customers of this size do not invite profiling; one large customer can skew a profile significantly. We believe that an accurate, acceptable settlement process can work only if all large customers are individually telemetered. We therefore set a telemetering *requirement* for these largest customers. We do not, however, require telemetering for any other group of customers. We invite comment on whether telemetering should be required for a wider group of customers, and if so, why benefits of doing so will outweigh costs. Because this provision is necessary and the associated costs are partially sunk, the metering and data storage and processing costs of the provision will be borne by the transmission and distribution utility and will be assigned to the customers receiving the telemeters, to the greatest extent practicable.

We do, however, *allow* telemetering for smaller customers through provisions in Sections 3.B.1 and 3.B.2. We believe that the market will determine the customers for whom the benefits of hourly pricing will offset the higher metering and data processing costs. Therefore, we allow telemetering at the request of the competitive electricity provider and we require the competitive electricity provider to bear all associated incremental costs. Assigning the costs to market participants removes unnecessary cost responsibility from transmission and distribution utility ratepayers and improves the likelihood of economic efficiency in customer conversions. We are exploring the costs of stranded meters and who should bear those costs in Docket No. 98-482, Inquiry into Provisions for Interactions Among Transmission and Distribution Utilities and Competitive Electricity Providers Regarding Metering, Billing and Collection, Service Commencement, and Service Contract.

We take seriously the need to implement provisions that are workable. We are concerned that, should wide-scale telemetering be requested, it will be difficult for transmission and distribution utilities to purchase and install the meters, implement the communication technologies, and accommodate the data storage volume. Increasing computer capacity and expanding computer programs or system solutions has long been a barrier to more complex billing operations at some utilities. To address this concern, we recommend a phase-in approach to optional telemetering. Section 3.B.1 specifies that only customers with maximum demands that exceed 200 kW may receive telemeters for settlement purposes in the first year after open access begins. Section 3.B.2 specifies that customers with maximum demands that exceed 100 kW may receive telemeters in year 2. As stated in Section 3.B.3, we will observe how successfully transmission and distribution utilities can accommodate those requests before determining the speed with which remaining customers are afforded the ability to receive telemeters.

We recognize that no one can predict the level of activity that will be demanded during the early years of open access. Consequently we cannot determine the best breakpoints for limiting activity in the early years. We invite comment on the levels we are recommending in the proposed Rule, and request parties to discuss the benefits and risks of this phase-in approach.

Finally, we note that this rule does not address specific meter technologies or standards. Metering requirements will influence telemetering costs and will be considered in another proceeding initiated by this Commission.

E. Section 4: Load Profiles

Section 4 describes processes and methods for developing load profiles. Load profiles will be developed for groups of customers for whom telemetering is not economically efficient. Virtually everyone involved in restructuring acknowledges that the most accurate way to determine the hourly load obligations of each competitive electricity provider is to telemeter its customers, thereby receiving true hourly load at the end of each day. All acknowledge, however, that the cost of such metering is not cost-justified for all customers, and particularly not for small customers. Some claim, however, that the cost of telemetering will drop as the market unfolds.

Because telemetering is required only for customers whose load exceeds 400 kW, load profiling is required to estimate the hourly load patterns of all remaining customers. Commenters did not state a firm preference for a particular breakpoint below which profiling would occur.

1. Section 4.A: Load Profiles for Customer Groups

Section 4.A.1 specifies that a load profile must represent an average customer in the group being profiled. Thus, while the profiles of a group will differ by transmission and distribution utility, they may easily be compared for similarity. The paragraph also explains that a load profile represents a type of day (e.g., a weekday in December or a "hot" day in summer), and allows transmission and distribution utilities to determine the most useful day type indicators.

Section 4.A.2 defines the three customer groups for which a load profile must be developed. Most commenters supported three groups (residential, small commercial/industrial, and large commercial/industrial) as being simple and adequate. Some commenters believed that further stratification would be necessary over time, to create groups with less diversity. Some commenters believed that division into groups of interest to the competitive electricity provider should occur. Rate classes (another reasonable grouping) differ among transmission and distribution utilities and in any event are becoming increasingly more difficult to define as special pricing proliferates. Grouping by end use or industry type introduces complexity without compelling benefit. We believe that the profile groups should be consistent across the state and should not advantage any one competitive electricity provider. We therefore propose the three simple classes supported by most commenters, and we choose 50 kW as a breakpoint between “small” and “large” because it is reasonable and consistent with some existing transmission and distribution utility rate classes.

Section 4.A.3 allows transmission and distribution utilities to create deemed profiles for groups of customers whose load patterns are predictable by the nature of the technologies within the group. Examples of such groups are streetlights and traffic lights. We leave it to the transmission and distribution utility to develop reasonable deemed groups and their profiles.

2. Section 4.B: Profiling Methodology

Section 4.B defines allowable statistical techniques for choosing the samples that will be metered from each customer profile group. The techniques are generally accepted and have been used in the electric utility industry since the advent of widespread load research was prompted by PURPA in the late 1970s. Our intent is to provide enough specificity to allow all affected parties to be certain that a transmission and distribution utility is producing load profiles in conformance with the provisions of this Rule.

Section 4.B.1 requires sampling techniques that target statistical accuracy of 90/10 for each of two measurements - group load at the time of the transmission and distribution utility's winter peak and group load at the time of the transmission and distribution utility's summer peak. Statistical theory requires that accuracy refer to a particular variable of interest. Although we are interested in the accuracy of load estimates for every hour of the year, it is not practicable to choose 8760 variables of interest. We chose load at system peak because it is a measurement that is needed in other applications (for example, cost allocation) and because no other measurement is clearly preferable for market settlement purposes. We chose both summer and winter peaks because either one may be the transmission and distribution utility's system peak, and because winter is likely to be the peak period in the Maritime bulk power system while summer is likely to be the peak period in the New England region. Two peaks offer the additional benefit of allowing a check for 90/10 accuracy twice during the year rather than once, which we believe is necessary during the early transition years.

Section 4.B.2 specifies that samples must be revised when they no longer maintain 80/20 accuracy. The proposed Rule relaxes the 90/10 sampling accuracy to avoid costly resampling. It is likely that attrition to telemetering will be rapid during the early stages of open access. As customers install telemeters, they will no longer be members of a profile group, causing the load patterns of that group to change. Since we cannot predict the speed of attrition, we will not specify a frequency for sample revision, but will rely on statistical accuracy to indicate the need to resample. We propose that transmission and distribution utilities over-sample, allowing sample accuracy to be maintained without the costly need to choose a new sample altogether.

Section 4.B.3 specifies that samples be chosen using the widely accepted statistical methods of either simple random sampling or stratified random sampling. Transmission and distribution utilities shall determine the criteria for stratifying samples but in all cases shall use widely accepted, documented statistical procedures.

Section 4.B.4 specifies that sample meter readings be converted to estimated class values through the widely accepted statistical methods of either ratio analysis or mean-per-unit analysis.

We seek comment on the validity of these specific statistical methods for use in this Rule. We are concerned that by stating specific methods, we will prohibit valid methods that are unforeseen today or that are already built into useful vendor software packages. We seek comment on these concerns.

F. Section 5: Daily Estimation of Competitive Electricity Provider Hourly Loads

Section 5 describes the process that each transmission and distribution utility must conduct at the end of each day to estimate each competitive electricity provider’s hourly load obligations. These estimations will be given to ISO-NE, which will use them to track the balance of generation and load in the bulk power system.

Section 5.A specifies that hourly loads at the point of delivery must first be estimated for each customer. We note that this step is a preamble to adding customers’ loads into an aggregate provider load. We do not require that the computer explicitly store each customer’s estimates, but that the process must conceptually mirror their calculation.

Telemetered customers’ loads will equal the meter readings. Profiled customers’ loads will begin as the class load profile for that day, which represents an average customer. The profile chosen must represent conditions (e.g., time of year, time of week, and weather conditions) that are known to significantly influence load levels or patterns. The profile may either be chosen from a “proxy day” that is similar to the day being estimated, or a generic profile may be adjusted upward or downward through regression or some other form of analysis to reflect the influencing conditions. Each hourly load must then be adjusted upward or downward by the same ratio so that total daily kWh usage from the hourly loads will equal a “kWh usage factor” that is the best estimate of that customer’s kWh usage for that day. The proposed Rule is silent as to the best way to calculate each customer’s kWh usage factor because we believe there are a variety of valid estimation methods. However, we envision that a customer’s kWh usage factor is likely to be derived from its monthly kWh use in the same month of the previous year or its monthly kWh use in the previous month and that the factor's calculation is likely to include an adjustment to turn cycle-month kWh use into calendar-month kWh use.

Section 5.B specifies that all customer loads will be adjusted for line losses between the bulk power system meter and the point of delivery, to produce load used by each customer at the point of delivery to the transmission and distribution utility's territory. The loads served by each competitive electricity provider will then be aggregated by adding the hourly loads of each customer served by that provider.

In a perfectly modeled system, the sum of the loads served by all competitive electricity providers would equal the meter readings of the bulk power system meter in each hour. However, inaccuracies introduced by sampling and line loss variabilities will produce a difference between the bulk power system meter readings and the estimated system loads. These differences in each hour will be allocated to profiled customers.

At this point in the process, the transmission and distribution company will have developed an estimate of each competitive electricity provider's load obligation, in each hour of the day, as required by ISO-NE. These estimates will be provided to ISO-NE.

Finally, Section 5.B assigns responsibility for line losses to competitive electricity suppliers and requires that line loss estimates be differentiated by season and by voltage level. Further differentiation is not prohibited.

We invite comment on whether the numerical steps set forth in the proposed Rule define the appropriate method for determining competitive electricity provider daily load obligations. We welcome alternative suggestions, either as requirements or options, if those alternatives retain understandable consistency across the State. We seek comments on whether these steps will prohibit the use of valid software packages being sold on the market or introduce consistent biases in the inaccuracies that inevitably will occur.

G. <u>Section 6: Monthly Settlement of Competitive Electricity Provider Energy Use</u>

Section 6 describes the process that each transmission and distribution utility will carry out at the end of each month to re-estimate the load obligation in each hour of the competitive electricity suppliers operating in its territory. These estimates will be given to ISO-NE, which will use them to carry out the financial settlement that takes place after balancing load obligation and generation delivered by each competitive electricity provider.

In developing this section, we considered likely future developments in the ISO monthly settlement procedures. Currently, ISO-NE requires receipt of only a single monthly kWh energy difference for each competitive electricity provider. That difference is used to adjust the financial settlement determined by the hourly load obligations received throughout the month by a single monthly average price. We believe that this requirement will evolve, and that ISO-NE will require hourly differences at some future date. The proposed Rule requires transmission and distribution utilities to implement a process that will accommodate that evolution, thereby avoiding costly upgrades at a later date.

Section 6.A specifies that hourly loads be recalculated, incorporating updated estimates of each customer’s daily energy use derived from month-end meter reading for billing purposes. The proposed Rule is silent as to the best way to incorporate the updated usage estimates because we believe there are a variety of valid estimation methods. We expect that the method will recognize the fact that the updated meter readings are at the point of delivery and must be adjusted for line losses. We require recalculation of each hour in anticipation of future ISO requirements, as discussed in the previous paragraph.

Section 6.B specifies that the transmission and distribution utility will calculate the differences between the daily estimates and the month-end updated estimates.

Section 6.C requires that the transmission and distribution utilities report the differences for each competitive electricity provider to ISO-NE in the form required by the ISO. We recognize that ISO-NE, not the Commission, defines the values to be reported. The proposed Rule defines the most likely requirements given our knowledge today.

We invite comment on whether the numerical steps set forth in the proposed Rule define the appropriate method for determining competitive electricity provider monthly load obligations. We welcome alternative suggestions, either as requirements or options, if those alternatives retain understandable consistency across the State. We seek comments on whether these steps will prohibit the use of valid software packages being sold on the market or introduce consistent biases in the inaccuracies that inevitably will occur.

H. <u>Section 7: Information Access</u>

Section 7 specifies what entities have access to customer-specific load or billing data and to provider-specific load data. Overarching principles in determining these provisions are that a competitive electricity provider should be given easy, fast, and complete access to any data that is used for its own financial settlement and to any load or billing data of its own customers. On the other hand, customer-specific data should remain confidential with regard to all entities that are not directly serving the customer.

Section 7.A applies the overarching principles to hourly load estimations performed each day. The provision specifies that competitive electricity providers will receive daily load estimations automatically, without requesting it. Competitive electricity providers must, however, request customer-specific data, and will only receive it for the time period during which the customer received generation service from the requesting competitive electricity provider. The Rule does not require customer authorization to release load data to the customer's competitive electricity provider, but does require written customer authorization to release load data to any other entity. Other jurisdictions allow release of customer-specific load data upon verbal customer authorization subject to third-party verification, or upon simple third-party authorization. However, 35-A M.R.S.A. § 3205(3)(I) appears to prohibit any authorization other than written, and we adopt that constraint here. We invite comment on whether written authorization creates a barrier to the market operations of competitive electricity providers and if so, whether any interpretation of the statute other than ours appears possible.

Section 7.B applies the overarching principles to monthly energy settlement estimates.

Section 7.C specifies that customer group load profiles be made public. We expect that the hourly load estimates that comprise the profiles will be published on the Commission's web site, with some indication of each profile's day type or other relevant information. The Commission would also supply paper copies of the profiles upon request.

Section 7.D applies the overarching principles to monthly billing data.

I. Section 8: Data Transfer

Section 8 requires that electronic transfer of data calculated pursuant to these rules follow guidelines determined by an industry group that will develop guidelines for transfer of all data among transmission and distribution utilities, competitive electricity providers, and bulk power system administrators. We have allowed for the creation of that group in a separate order to avoid slowing the group's formation. See Docket No. 98-522, Investigation into Electronic Business Transaction Standards for the Exchange of Information in a Restructured Electricity Industry.

J. Section 9: Reporting

Section 9.A requires that transmission and distribution utilities submit to the Commission a description of their sampling, profiling, validation, and daily and monthly settlement methods before the advent of open access. The purpose of this report is to allow the Commission to maintain an understanding of the processes being followed in all areas affecting the implementation of open access. It also allows competitive electricity providers to understand each transmission and distribution utility's process with sufficient accuracy to predict its own daily load obligations.

Section 9.B requires that transmission and distribution utilities submit to the Commission an annual report whose purpose is to keep the Commission apprised of the effectiveness of the processes it has implemented through this Rule. The annual report should revise the original methodology report if necessary and should present suggestions for method or process changes.

Section 9.C requires transmission and distribution utilities to submit line loss studies by March 1, 1999 and March 1, 2001. Line loss estimates can have a significant financial impact on competitive electricity providers. While line loss studies have been submitted with utility rate cases in the past, we will now consider line loss values in light of their impact on the settlement process.

V. PROCEDURES FOR THIS RULEMAKING

This Rulemaking will be conducted according to the procedures set forth in 5 M.R.S.A. § 8051-8058. No public hearing on this matter is presently scheduled. A public hearing will be held if requested by any five interested persons. Persons wishing to request a public hearing on this Rule must notify the Administrative Director, Public Utilities Commission, 242 State Street, 18 State House Station, Augusta, Maine 04333-0018 (telephone: (207) 287-3831), on or before August 12, 1998.

Please notify the Public Utilities Commission if special accommodations are needed in order to make the hearing, if one is held, accessible to you by calling 1-287-1396 or TTY 1-800-437-1220. Requests for reasonable accommodations must be received 48 hours before the scheduled event.

Written comments on the proposed Rule may be filed with the Administrative Director no later than September 4, 1998. Please refer to the Docket Number of this proceeding, Docket No. 98-496, when submitting comments.

We are mindful of transmission and distribution utilities' need to commence implementation of the processes contained in this Rule. Therefore, we plan to complete this Rulemaking by October 31, 1998.

In accordance with 5 M.R.S.A. **§** 8057-A(1), the fiscal impact of the proposed Rule is expected to be minimal. A more precise understanding of the fiscal impact of this Rule should be possible once comments have been received. The Commission invites all interested parties to comment on the fiscal impact and all other implications of the proposed Rule.

The Administrative Director shall send copies of this Order and the attached Rule to:

1. All electric utilities in the State;

2. All persons who have filed with the Commission within the past year a written request for Notice of Rulemaking;

3. All persons on the Commission's electric restructuring service list, Docket No. 95-462;

4. Certain parties who have shown an interest in comparable cases in Massachusetts;

5. All parties listed on the service list or who filed comments in the Inquiry*, Inquiry into the Energy and Load Profiling and Settlement Functions of Transmission and Distribution Utilities in a Restructured Electric Industry*, Docket No. 97-861;

6. The Secretary of State for publication in accordance with 5 M.R.S.A. **§** 8053(5); and

7. Executive Director of the Legislative Council, 115 State House Station, Augusta, Maine 04333-0115 (20 copies).

Accordingly, it is

O R D E R E D

1. That the Administrative Director send copies of this Notice of Rulemaking and attached proposed Rule to all persons listed above and compile a service list of all such persons and any persons submitting written comments on the proposed Rule; and

2. That the Administrative Director send a copy of this Notice of Rulemaking and attached proposed Rule to the Secretary of State for publication in accordance with 5 M.R.S.A. § 8053.

Dated at Augusta, Maine, this 24st day of July, 1998.

BY ORDER OF THE COMMISSION

Dennis L. Keschl
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Nugent